Comments of the International District Energy Association on Development of Guidance on Updating Output Allowance System

Mark Spurr
Legislative Director, IDEA
March 9, 1999

Introduction

These comments address two major issues:

- Net vs gross output; and
- Comparison of steam and electric outputs

Net vs Gross Output

Allocations should be based on net output, but it is important to be clear about the definition. Net output is not necessarily what is sold and exported out of the plant. The output from a generator or boiler might be used within the plant boundary for process requirements, such as making widgets, supplying a district heating system or producing chilled water. These process requirements are not "parasitic" uses of power or steam, i.e., consumption associated with the production of these energy outputs such as pollution control devices. Net output should be defined as gross output minus parasitics. Even if the power plant or steam plant weren't operating, the net energy would still have to be produced to meet process requirements or supply power to the grid.

Thus, allocation of allowances for electricity output should be based on the sum of gross electricity outputs from all units in the plant minus the sum of the electricity consumption for auxiliary requirements associated with generating power or steam. Similarly, allocation of allowances for steam output should be based on the sum of gross steam outputs from all units in the plant minus the sum of the steam consumption for auxiliary requirements associated with generating power or steam.

If allocations are done on the basis of gross output, plant configurations with high auxiliary requirements (e.g., steam turbine power plants compared to combustion turbines) would have an advantage because they wouldn't be penalized for these losses. Similarly, plants with low auxiliary energy requirements would realize an advantage with a net output approach. That is acceptable and consistent with the policy objective: generate usable energy more efficiently and with less environmental impact.

Appropriateness of comparing and converting steam and electrical output

Should steam output be converted to electrical output? If so, which method should be used to convert steam energy to electrical power equivalent? If steam energy were not converted, how would emissions limitations be treated for cogenerators?

What assumptions, if any, should be made about the efficiency of conversion from steam output to electrical output?

How can steam be treated equitably for industrial boilers and cogenerators?

If steam output data were not available from industrial boilers, how would States allocate allowances to cogenerators?

Introduction

Thermal output should not be converted or compared to power output. It is not necessary or appropriate to equate the two in a generic way. These questions imply that the only Combined Heat and Power (CHP) situation to be considered is steam turbine power generation. This really isn't appropriate, because a variety of technology types are used for power generation and for CHP, as explained below. The idea of "converting" steam to electricity doesn't reflect the physical reality in many CHP situations, and fixing this relationship ignores the fact that the relative efficiencies of electric generation and thermal generation will change over time as more efficient power generation technologies, such as combined cycle plants, come on line.

Power Generation and CHP Technologies

Major Power Generation Technologies

- *Gas turbines* are basically like jet engines (in fact, many commercial systems are so-called "aero-derivatives," i.e., they are directly evolved from aircraft engines). Natural gas is combusted and the hot gases drive a turbine that spins a generator.

- In *steam turbine* power plants (the most common type of plant in the world today), fuel is burned to make steam, which drives a turbine that spins a generator.

- In *gas turbine combined cycle* plants, the hot gases exiting from the gas turbine are used to make steam, which drives a separate steam turbine that spins a generator.

- *Reciprocating engines* (e.g., diesel engines) can also be used to generate electricity. These internal combustion engines convert fuel to shaft power, which then spins a generator.

Waste Heat

In electric-only power plants, most of the energy input to the plant ends up as waste heat. In gas turbines all of the energy in the exhaust gases is wasted. Plants employing a steam turbine (either steam turbine or gas turbine combined cycle plants) condense the steam exiting from the turbine. This boosts the power output by creating a vacuum on the exit end of the steam cycle, thus making the steam turbine spin faster. However, most of the energy then ends up in the condenser cooling system (using cooling towers that put the heat into the air, or dumping the heat into a body of water such as a river).

Combined Heat and Power (CHP)

Cogeneration or CHP is usually defined as a process in which electric energy and useful thermal energy are produced sequentially using the same input fuel. With cogeneration, the other-wise-wasted heat is absorbed by a district heating system, industrial steam load or other thermal load, or is converted to cooling for district cooling or industrial process cooling using steam turbine chillers or absorption chillers. For example:

- In a gas turbine plant, all of the heat in the exhaust gases is available. The exhaust gases are used to make steam in a Heat Recovery Steam Generator (HRSG).

- In a steam turbine or gas turbine combined cycle plant, heat can be obtained several ways. In backpressure steam turbine CHP, the available heat is what would otherwise be dissipated in the cooling towers. In this case, the steam exiting the turbine goes to a heat exchanger instead of a condenser. Steam can also be extracted from the turbine part-way through its transit through the turbine. Extraction is required if a higher-temperature thermal output is required.

- In a reciprocating engine there are a variety of heat sources including the water used to cool the engine (jacket water), hot lubricating oil and other sources. The amount of heat available depends on the temperature required; some of the waste heat sources have a relatively low temperature.

Key numbers

Before getting into the structural issues, let’s review some of the relevant numbers.

EPA has set the input-based allocation rates as follows:

EGU	0.15 lbs per million Btu fuel input
Non-EGU (industrial)	0.17 lbs per million Btu fuel input

These input-based rates can be converted to output-based rates by applying an efficiency factor. A reasonable assumption for a new steam turbine power plant would be 34%, whereas a new gas turbine combined cycle plant might have an efficiency of 55%. This is illustrated in Figure 1, with the associated input-based allocation rates shown in Figure 2.

Applying these efficiency factors to the input-based allocation rates yields output-based rates illustrated in Figures 3 and 4. Figure 3 shows output rates in lbs. per million Btu output. In Figure 4 these rates have been converted to lbs. per MegaWatt-Hour output (one MWH = 3.413 million Btu).

The efficiency of industrial boilers is not subject to a lot of variation. Therefore, the ratio of the industrial output-based rate to the EGU output-based rate depends primarily on the efficiency of the EGU. For the examples shown, this comparison is illustrated in Figure 5:

- 48% assuming a steam turbine power plant (about the factor assumed in the proposed "conversion" of steam to electricity by applying a 50% "conversion factor"); or it could be

- 78% assuming gas turbine combined cycle, the technology that is likely to dominate in the new capacity coming on line in the coming years.

Why freeze the relationship of thermal to electric output based on an arbitrary "conversion factor" when the differences in efficiency between electric generation and steam generation will change over time as the electric generation plant mix includes more and more high-efficiency technologies, particularly combined cycle plants?

Figure 1

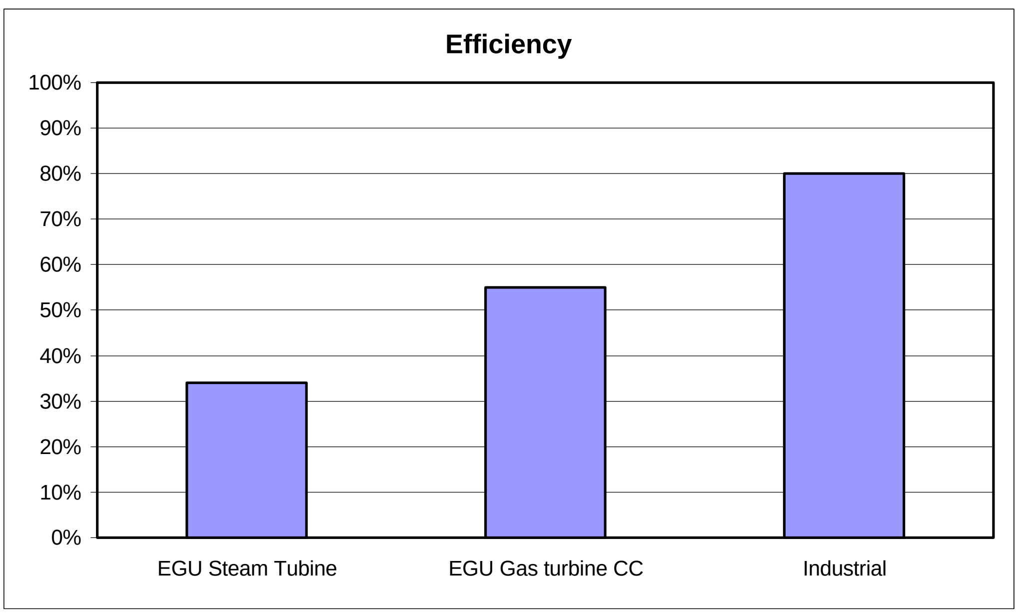


Figure 2

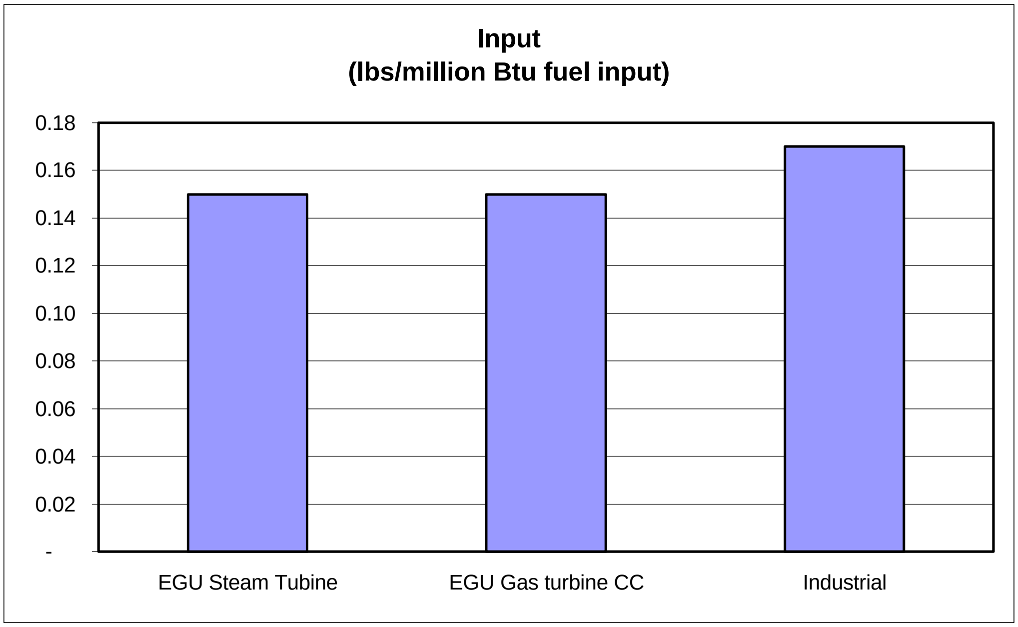


Figure 3

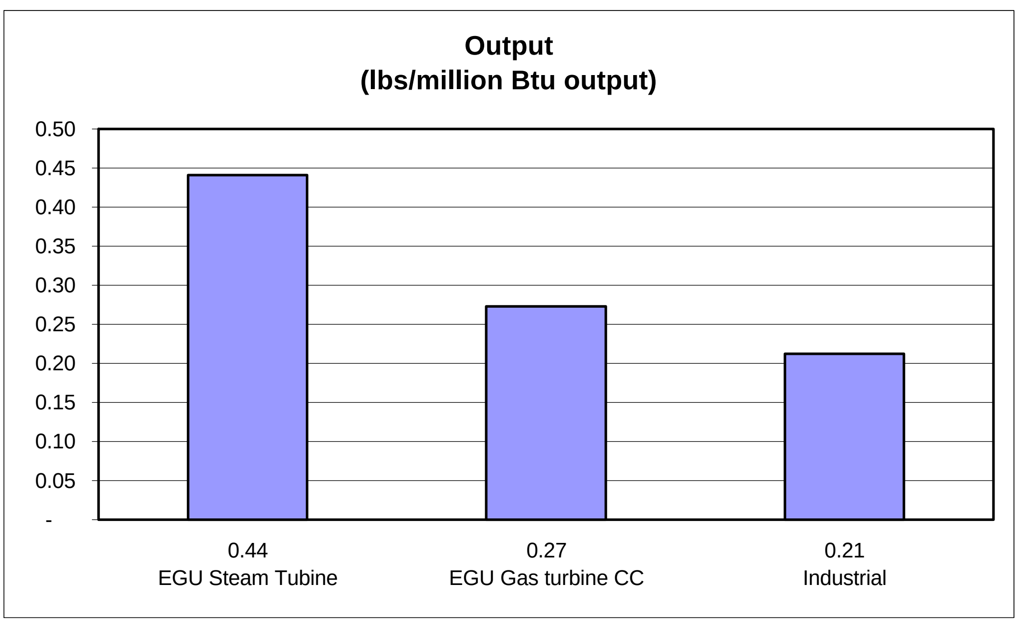


Figure 4

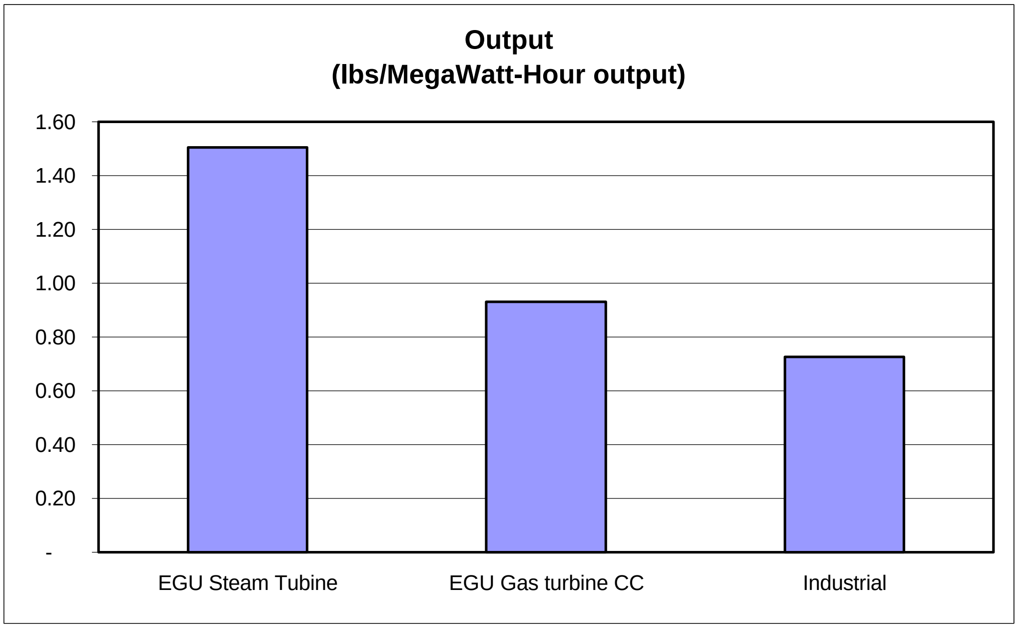
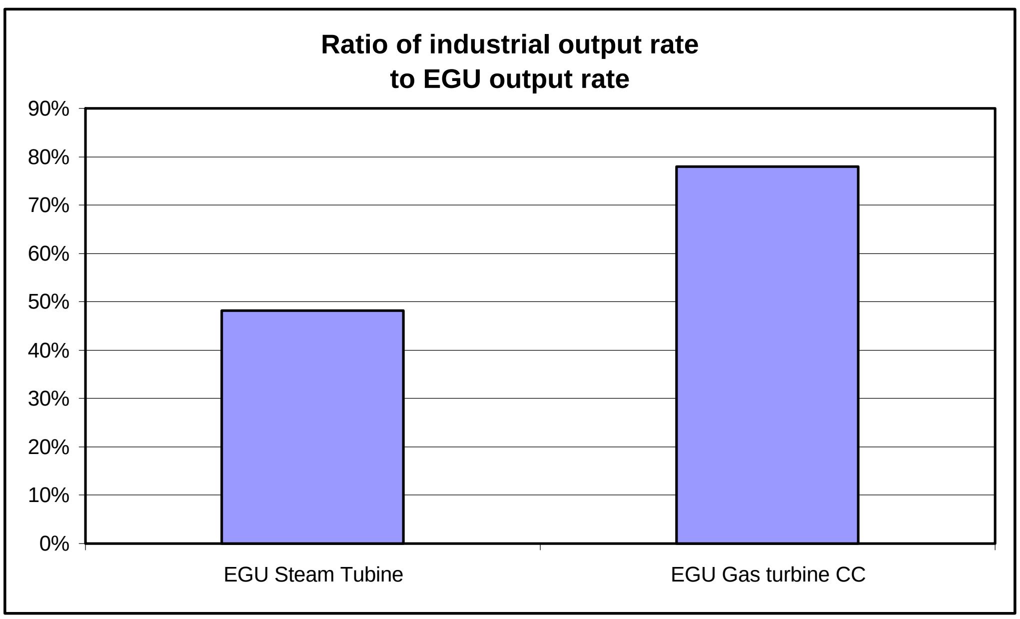


Figure 5



Allocation process with two pools

How should allowances for electric and thermal output be allocated? The answer depends on the larger structural issue one pool vs two pools: one for Electric Generating Units (EGU) and one for non-EGU (industrial). The two-pool approach is part of the existing model rule. However, in theory, states could adopt a different approach, potentially with only one pool of allowances.

Let's first approach the issue assuming two pools. In this case, the following steps could be used:

1. Set the nominal allocations to each facility, including CHP facilities, using the nominal output-based rates, which could initially be 1.5 lbs per MWH electric output for EGUs, and 0.21 lbs per million Btu (MMBtu) for non-EGUs. CHP facilities would be allocated allowances for both the electric and thermal output, using the respective output-based rates.

2. The allocation rates would then be normalized, i.e., adjusted to reflect the available allowances in each pool:

$$\text{normalized allocation rate} = \text{nominal allocation rate} \times \frac{\text{available allowances in pool}}{\text{total nominal allowances in pool}}$$

3. Final allocations to each facility would then be made based on the adjusted allocation rates, with CHP facilities receiving allowances from both pools.

Allocation process with non-EGU allocations based on input

If obtaining output data in non-EGU facilities was deemed to be too difficult, the following process could be used:

1. Establish a factor for converting cogenerated thermal output to a fuel input, based on representative sampling of non-EGU boiler facilities. This might be on the order of 75-80% efficiency.

2. Set the nominal allocations to each facility. CHP facilities would be allocated allowances from both the EGU pool (using the output-based rate per MWH electric output) and from the non-EGU pool (using the input-based rate applied to the thermal output converted to fuel input).

3. The allocation rates would then be normalized, i.e., adjusted to reflect the available allowances. In other words, the adjusted rates would be the allowance pool divided by the total output or input allocable to that pool, as presented above.

4. Final allocations to each facility would then be made based on the adjusted rates.

Allocation process with one pool

At the Feb. 3 meeting it was asserted that some States may prefer to have only one pool. The advantage of such an approach is not clear to me, since as far as I can see the same data will still have to be obtained and crunched if allocations are to be made on an output-basis. For example, the State would still have to track the number of MWH of electric output and million Btu of thermal output. However, even with one pool, allocations can be made for electric and steam output as follows:

1. Set the nominal allocations to each facility, including CHP facilities, using the nominal output-based rates, which could initially be 1.5 lbs per MWH electric output for EGUs, and 0.21 lbs per million Btu (MMBtu) for non-EGUs. CHP facilities would be allocated allowances for both the electric and thermal output, using the respective output-based rates.

2. The allocations to each facility would then be normalized, i.e., adjusted to reflect the total allowances available:

$$\text{normalized facility allocation} = \text{nominal facility allocation} \times \frac{\text{total available allocations}}{\text{total nominal allocations}}$$

"Transfer"

The issue has been raised that a "transfer" occurs when a CHP facility draws some allowances from the non-EGU pool even though its baseline was counted completely in the EGU pool. This should not be viewed as a problem. An updating output allocation process is an inherently a dynamic one, with re-allocation occurring as a matter of course. This would simply be a manifestation of a trading system doing its job.